Volume 59, Number 11
November 1981

C8650-4

0911 25 1830645 1 W JPK
JOSEPH MCNALLY
CONGRESSIONAL INFORMATION
SERVICE INC
4520 EAST-WEST HWY-STE 800
WASHINGTON DC 20014

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Atlantic Electric is 1981 award utility

Atlantic Electric Co. has been named *Electric Light & Power*'s 1981 Outstanding Electric Utility of the Year. The utility was chosen by a panel of industry judges to be the 13th winner of the annual award.

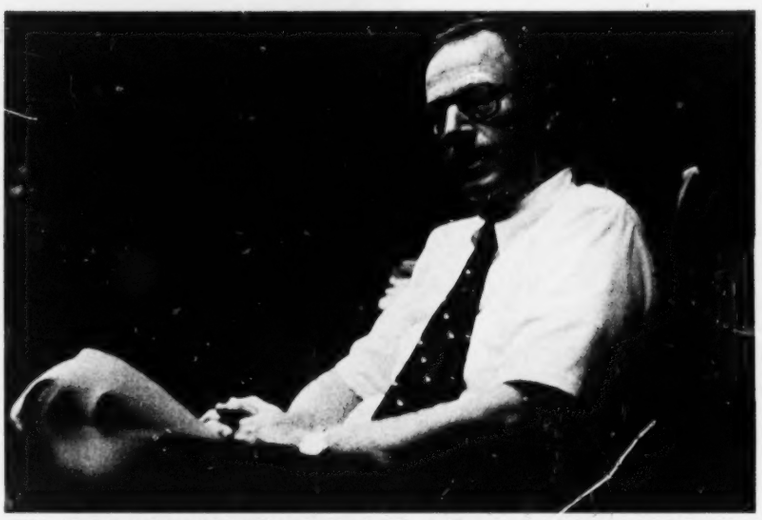
EL&P Editor Robert Lincicome said the award was based on an impressive three-year financial record, the utility's leading role in converting oil-fired generating capacity back to coal, and an innovative communication program.

Utility president and chief executive officer John Feehan expressed appreciation for the award and noted that the company faces even stiffer challenges in coming years. With growth in demand in recent years sparked by the introduction of nine gambling casinos and hotels in Atlantic City, the utility must deal with unprecedented capital requirements that total twice the company's current assets in the next decade, Feehan said. (One interesting technique being explored for raising capital at Atlantic Electric is explained in the article below.)

Over the past three years the utility has recorded an almost unmatched record of improvement in earnings: a seven percent gain in 1978 to $2.21 a share; another seven percent increase in 1979 to $2.36 a share; and an eleven percent rise in 1980 to a record $2.36 a share.

The special report on Atlantic Electric begins on page 13.

Part of the impressive earnings record is due to the company's swift replacement of imported oil with coal as a power plant fuel. When the company's largest generating station, the B.L. England station, was converted to oil for environmental reasons in the early 1970s the company retained all the coal-burning equipment and kept it maintained. The station was back on coal one month after the 1973 Arab oil embargo, making it the first utility to convert back. The company is now converting its other major station, the Deepwater plant, back to coal also and is aiming at reducing its oil dependence to 10 percent.



Atlantic Electric president John Feehan explains how he and his management team achieved such impressive corporate results in recent years.

European equipment suppliers offer low-cost power plant financing

A highly unusual foreign financing and supply deal is being negotiated for Atlantic City Electric Co.'s proposed new 290-MW coal-fired Cumberland power plant, according to utility president John Feehan. By using largely foreign equipment for the plant, the utility hopes to get access to foreign capital at money costs much lower than those now prevalent in the U.S., shaving as much as $100 million off the $550 million estimated cost of the power plant, Feehan revealed during an interview .

This is not the same as the "Eurodollar" or "Eurobond" financing at interest rates of 17 or 18 percent which is becoming increasingly popular with U.S. utilities. In those deals the interest rates are at best only slightly better than those in the U.S. Atlantic City Electric wants the borrowing to take place at substantially lower rates by going through foreign suppliers.

Two European suppliers, Cogenel ("French General Electric") and Brown-Boveri, the Swiss firm, have responded so far, reports Feehan. One of the proposals was extremely broad based, covering equipment, construction, financing, "everything", according to the executive.

Feehan says the search for lower interest rates is part of the company's overall program to do all it can to slash capital costs. Atlantic Electric is trying to dampen demand to avoid, or at least put off the need to build the new power plant. But if demand continues to grow, Feehan says that a large block of new company-owned capacity will be needed in the late 1980s. He's not sure that financing such a project is even possible at current U.S. money rates.

Access to the much lower interest rates in some European countries may make it possible to proceed with the generating project, he explains. "We'd like to go American, but these proposals may unlock the door."

Company officials are weighing the risks of extensive reliance on a foreign supplier. They're evaluating equipment quality, servicing, spare parts availability, and other factors. "Our knee-jerk reaction," says Feehan, "is not to go foreign. But it's a very interesting prospect. We have to be flexible."

Paul Hughes, a manager with Brown-Boveri Corp.'s U.S. office in North Brunswick, N.J. said he would prefer not to discuss the details of the company's proposal for the Atlantic City Electric project because formal bids have not been made yet. Hughes explained that utility officials had solicited an equipment bid including a request that Brown-Boveri aid in financing.

The utility managers are seeking access to money at Swiss bank loan rates, said Hughes, which are currently about seven percent. "We're not in any position to get any special deal for Atlantic City Electric," said Hughes. "We're using our knowledge and connections as a Swiss manufacturer. These are bank loans. All it is, is making the introductions. These are not supplier credits."

Hughes said that Brown-Boveri had not made a turnkey proposal. The company does build power plants on a turnkey basis, but only in places such as the Far East or the Mideast, not in the U.S. The firm does not like to engineer U.S. power plants because it doesn't want to "tread on the toes" of U.S. architect-engineering firms, Hughes explained. He noted that the Swiss company was recently awarded a $30 million contract for a turbine-generator for a U.S. coal-fired power plant by the Grand River Dam Authority of Vinita, Oklahoma. The company is not looking to go beyond its normal scope of equipment supply or to provide engineering on coal-fired power plants in the U.S.

A spokesman for Utility Power Corp-Corp. said his firm declined to respond to the request to make a proposal for the Cumberland project. The company is partially owned by Siemens, the West German equipment supplier. The spokesman said that the Atlantic City request was unusual in that they were seeking to build a power plant with equipment purchased in Europe with European financing. He said that his firm did not want to participate because there would be too many opportunities for misunderstanding with all European equipment and a U.S. design.

EL&P® Late News

President Reagan issued his nuclear policy statement in early October and the policies and actions he announced were aimed at what he termed "a revitalization of the U.S. industry's effort to develop nuclear power." There reportedly will be an effort to streamline the time it takes to construct and license a nuclear plant—from 10-14 years to 6-8 years. To those who thought the President might retreat from his earlier support of the Clinch River breeder reactor—as he scoured the bureaucratic landscape looking for additional budget cuts—Reagan offered this: "I am directing that government agencies proceed with the demonstration of breeder reactor technology, including completion of the Clinch River Breeder Reactor. This is essential to ensure our preparedness for longer-term nuclear power needs." The President lifted the ban on commercial reprocessing and has ordered a study to assess the feasibility of obtaining economic plutonium supplies for the Department of Energy through competitive procurement. He said DOE and industry must toward deployment of a means of storing and disposing of commercial high-level radioactive waste." Finally, the President said he has formulated a task force that will seek to identify any and

Continued on page 2

Reagan reversal

Administration to push for $100 million for TMI cleanup

WASHINGTON, D.C.— The Reagan Administration has decided it will recommend over $100 million for the cleanup of the contaminated Three Mile Island reactor.

The decision constitutes a reversal of an earlier position assumed by the White House that it should only be responsible for waste management and some research and development activities with respect to the downed reactor.

Word of the possible federal funding came through two statements made by budget director David Stockman. After attending a fund raising event in Pennsylvania on October 9 Stockman held a local press briefing where he revealed that the federal government would contribute over $100 million to help clean up the mess at TMI-2.

The wire services picked up the remarks and Stockman was questioned about it again at the White House the next day. He repeated the government's planned commitment.

Continued on page 6

EL&P® Late News

all obstacles that currently stand in the way of the increased use of nuclear power. The task force is to report to the President by September 30, 1982, informing him not only of impediments to nuclear power development but steps that are needed to overcome them. "Eliminating the regulatory problems that have burdened nuclear power will be of little use if the utility sector cannot raise the capital necessary to fund construction of new generating facilities," Reagan concluded. "We have already taken significant steps to improve the climate for capital formation with the passage of my program for economic recovery. The tax bill contains substantial incentives designed to attract new capital into industry."

The federal government should take title to spent fuel and rad-wastes in return for a concession by nuclear utilities that they will pay a fee based on nuclear kilowatt hours sold. This was one part of Sherwood Smith's testimony recently on behalf of the electric utility industry before a joint hearing of the Senate Environment and Public Works Committee and the Senate Energy Committee. Smith, who is head of Carolina Power & Light and chairman of the Edison Electric Institute's policy committee on governmental affairs, also called for legislation in the area of nuclear waste management. "We firmly believe that the legislation should authorize and direct the secretary of energy to enter into contracts with all nuclear plant operators by which the government agrees to take title to and responsibility for radioactive wastes or spent fuel by a specific time, in return for the commitment of the utility to collect from its customers and pay to the treasury a fee of one mill per kilowatt-hour of nuclear generated electricity for all nuclear fuel removed from nuclear reactors," Smith said. He said that legislation was necessary to ensure policy stability amid changes of administration and changes in Congress. Legislation, Smith added, could also work to define the role of the states and Indian tribes so that disputes and delay could be avoided. Finally, legislation would clarify the issues needed to prepare an environmental impact statement. Smith said that utilities support the concept of a test and evaluation facility that does not delay the overall geologic respository program or add significant costs to the waste management program. He also supported the establishment of a federal interim spent fuel storage program.

NARUC has formed an *ad hoc* committee on utility diversification. The committee, which consists of eight members, will review the 1972 report prepared by NARUC's *ad hoc* committee on non-utility investments. This diversification committee of the National Association of Regulatory Utility Commissioners will revise the 1972 report as necessary in order to increase its current value to the regulatory community. The *ad hoc* committee on utility diversification includes the following members: Stanley York, chairman of the Wisconsin Public Service Commission and chairman of the *ad hoc* committee; Thomas H. Fitzpatrick, chairperson of the Connecticut Public Utilities Control Authority; Edward B. Hipp, commissioner, North Carolina Utilities Commission; and Francis J. Riordan, commissioner of the New Hampshire Public Utilities Commission. Also serving on the *ad hoc* committee are Henry Moak Rollins, commissioner, Texas PUC; Richard E. Schuler, deputy chairman, New York PSC, Larry J. Wallace, chairman, Indiana PSC; and John W. Winters, Sr., commissioner, North Carolina Utilities Commission.

In This Issue

Editorial 4

Atlantic City Electric Co. is the winner of the 1981 utility of the year award ... 13

Trends in the sulfur market toward higher prices and tighter supply may affect utility decisions on the type of scrubber to be used on coal-fired power plants. **E/G** 21

Repowering a reheat cycle, oil- or gas-fired power plant with a coal-fueled combined cycle may make economic sense, says Westinghouse. **E/G** 24

A new scrubber technology that provides particulate and sulfur dioxide removal in a single-state venturi is working well at Arizona Public Service. **E/G** 26

Creativity in specialized equipment and scheduling speeds construction of 230-kV T-line, H-frame towers to pace of 28 towers per day. **T/D** 47

PCB-capacitor rupture possibilities can be reduced economically with existing devices and better fusing techniques. **T/D** 50

Three new developments in herbicide application techniques promote economy and improve public acceptance of ROW maintenance and growth control. **T/D** 54

IEEE/PES Conference and Exposition held in Minneapolis was a big show with emphasis on new products and improved technical communications. **T/D** 60

Reader Service 85

New Products 87

New Literature 88

Advertisers' Literature 92

Personnel 94

Regulatory Review 104

Management Methods 105

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Diablo Canyon protestors to regroup while design problem delays startup

Dan Utroska
Associate Editor

AVILA BEACH, CA— The anti-nuclear protestors at the Diablo Canyon nuclear plant got an unexpected assist in September as the revelation of a seismic design problem threatened to delay startup of the reactor for as much as six months.

In addition, even as protestors were attempting to block access to the plant, Governor Brown of California, an avowed opponent of Diablo Canyon, filed a suit in the U.S. Court of Appeals for the District of Columbia Circuit charging that the Nuclear Regulatory Commission had issued the low power testing license for the plant contrary to applicable laws and statutes.

Annulus braces questioned

"We have uncovered a discrepancy that has possible safety concerns," a spokesman for Pacific Gas & Electric Company said. On September 27, utility personnel found that a reference diagram for unit 2 at Diablo Canyon had been used in the design and construction of unit 1. The reference diagram was used to determine the vertical acceleration and frequency response factors of equipment braces in the annulus. The error was discovered when utility personnel, working on unit 2, found that the application of annulus brace data for that reactor was off by a mirror image. Since unit 1 plant layout is a mirror image of unit 2, it was concluded that a design error had occurred. PG&E notified the NRC.

It was not clear in mid-October the extent of the delay that would be experienced as the NRC considered the matter. The utility had set up a meeting with the NRC to inform the agency of the results of its new calculations after the mistake had been identified. But the utility subsequently asked for more time and a meeting between PG&E and the NRC had been reset for October 9.

The significance of the error, while still to be determined, touched on the very issue that Abolone Alliance protestors fear: the capability of the Diablo Canyon nuclear plant to withstand an earthquake. According to Darrell Eisenhut, director of the NRC's Division of Licensing, the Diablo Canyon annulus brace design data used in construction of the plant would determine how equipment there would respond during a seismic event.

The PG&E spokesman said that from a technical standpoint, the situation could be resolved in a couple of months, but what the utility fears is that the NRC will decide to reopen hearings on the plant. This would extend the time the plant is on hold.

Abolone Alliance: success redefined

The Abolone Alliance, a loosely-knit group of about 60 "safe-energy" organizations, had originally set out to force the utility and the Nuclear Regulatory Commission to sign an agreement that Diablo Canyon would never operate as a nuclear plant (see *EL&P*, September, 1981, page 2). The groups' approximately 15 day protest at the site, where about 2,000 demonstrators were arrested, failed to accomplish this, but the annulus brace problem has given the Alliance a chance to retreat and regroup. "We are by no means finished," Alliance spokesperson Marilyn Apuzzo told *EL&P*. She said that a statewide conference had been set for the weekend of October 10-11 to discuss plans for sending Diablo Canyon participants back to their communities in an effort to mobilize a renewed contingent of demonstrators. "The blockade is the end of phase 1," Apuzzo said.

Although the Alliance did not get the agreement it sought, the group believes it has heightened the visibility of the dangers of nuclear power. Alliance spokesperson Apuzzo reiterated a remark attributed to a PG&E representative, that "without the blockade, we would have read about (the brace design problem) on page 33 of the newspaper."

The Alliance is sued

Although Pacific Gas & Electric said the demonstration had caused "no significant slowdown in fuel loading, low-power testing preparations or construction of the unit," the Pacific Legal Foundation, representing a group of aggrieved organizations and individuals, believes a case can be made that the utility has incurred extraordinary expenses and should be compensated. Accordingly, the foundation has filed suit seeking recovery of PG&E costs for such items as special buses that were needed to bring workers through the blockade, the helicopter used for that purpose and the extra security personnel that had to be employed.

This, according to Pacific Legal Foundation attorney Hal Hughes, is one part of the $1 million lawsuit that was filed against the Alliance on September 25. The other part seeks to recover the costs to area taxpayers for the extra law enforcement efforts caused by the blockade.

The Pacific Legal Foundation, a conservative organization, says it has the support of four groups and five individuals in its suit against the Alliance. Included in the organizations providing support are Consumer Alert, said by Hughes to be a national, nonprofit consumer organization, the Voice of Energy, and a San Luis Obispo coalition of taxpayers, farmers, and others called the "Countywide Coalition for Less Government."

Leading the individuals supporting the PLF suit is California state congresswoman Carol Hallett. Mrs. Hallet represents the district in which the demonstration took place. According to Hallett spokesman Jack Stevens the lawsuit is not about the pros and cons of nuclear power but is a "test of whether persons can demonstrate illegally and then make taxpayers pay for it."

The broad basis of the suit rests on the "nuisance" the protestors caused, Stevens said. Claiming that the illegality of the protest precludes the demonstration from being viewed as a First Amendment expression, Stevens said the demonstrators blocked roads and generally caused some taxpayers to do without normal law enforcement services while personnel were transferred to the nuclear plant site. Is such a lawsuit unique, Stevens was asked. "I have no knowledge that this has even been tried before," he said.

Alliance undeterred

According to Alliance spokesperson Marilyn Apuzzo, the $1 million lawsuit against the anti-nuclear group will have no inhibitory effect on planned actions. She said that a number of attorneys had already volunteered their legal services and that as a result of the publicity of the Diablo Canyon blockade, persons from all over the country were sending in money. "We can deal with it," she said.

Branding Rep. Hallet's action as a "scare tactic" and an effort "to dissuade our action," Apuzzo said the lawsuit was little more than a "political ploy" on Hallett's part. "She wants to make an issue out of it in her run for Lt. Governor," Apuzzo said, but Hallett spokesman Jack Stevens said Mrs. Hallett had not declared for the office of Lt. Governor and that the congresswomen was only one party to a lawsuit that was being brought by numerous independent plaintiffs.

Deregulation may help, Mellon Institute says

Kilowatt hours too costly to compete, study claims

The sale of centrally-generated electricity could be in for some difficult times if economic forces move to displace political ones in U.S. energy policy.

This is a major conclusion of a recent study by the Mellon Institute that undercuts the conventional wisdom surrounding the so-called energy crisis. "Shifting from a political to an economic paradigm for energy does more than demonstrate the falseness of many of our beliefs about energy," the report declares. "It points the way toward new means of effective action in meeting energy service needs."

The study, called "Eight Great Energy Myths," is an update of a 1979 Institute analysis that assumed the elimination of regulations affecting energy choices. Consumers really don't care about kilowatt hours or Btu's, the earlier study found, so long as they can obtain comfort and convenience in their homes, and steam and operating machines in their factories. When energy is viewed in this way, fuel and electricity are seen as only one part of what is needed to provide useful services. In making a room comfortable, for example, components such as a furnace, a thermostat, duct work, insulation, and numerous other support items are also required. What is important, the study found, is putting these together so that they reflect the lowest cost. This often means a reduced fuel component in providing the total service.

By shifting the focus from energy fuels to currently available "productivity (conservation and efficiency-improving) technologies" to meet human needs, researchers at the Mellon Institute's Energy Productivity Center came up with a number of startling results, some of which carry gloomy implications for the electric utility industry. For example, it is currently believed that the only way out of utility financial difficulties is through meaningful rate relief. Yet, according to Dennis W. Bakke, deputy director of the center, that organization's findings do not support this idea. "The reason (electric utilities experience financial difficulties) is that the product itself is in trouble," Bakke told *EL&P*. "Price increases have made it less competitive than it has been in the past."

The revised Mellon study, which is said to project the least-cost fuel mix and technology investment patterns through the year 2000, shows coal and nulcear generated electricity will rise only about one-half as fast as growth figures put out by the government's Energy Information Administration (EIA) suggest (see Figure 1). While the Mellon study emphasizes that these projections are not forecasts of what will happen, they are said to demonstrate what is possible "if known energy technology is applied on the basis of economic self-interest."

Industrial co-generation is seen as being responsible for dampening centrally-generated electricity from now until the year 2000. "There are thousands of co-generation studies going on in industry today," Bakke said. "I would bet my money that industry will follow economic arguments." He added, "We will find ways to make this happen. This is the message to central station electricity generators."

There appears to be other areas where electricity is not competing very well, Bakke said. Lighting is one such area. Acknowledging that lighting did not constitute a large electric market, Bakke nonetheless noted that technological advances here, which now provide lighting with a fraction of the electricity previously needed, have been dramatic. "The market share of electricity is being taken by the light bulb manufacturers," he said.

"To say you can solve . . . utilities' problems by raising rates is much like saying we could solve the problems of Chrysler by raising the price of their automobiles."

As shown in Figure 4, delivered energy demand for electricity produced at central stations (exclusive of station generation losses) is almost flat through the 1980's (down about 6 percent over the period) and then increases by about 1.0 percent per year during the 1990's. Coal and nuclear are assumed to be replacing oil and gas as power sources in central station generation at the same rates projected by the EIA. *Total* electricity growth, including both centralized and decentralized generation, amounts to 0.8 percent in the 1980's (the 6 percent decline in central station output being more than offset by contributions from co-generation) and 1.3 percent in the 1990's (the 0.3 percent here coming from co-generation).

Industrial demand and co-generation

The Mellon study found that under least-cost conditions, industrial energy use would continue to increase during the century. However, during the 1980's industrial consumption from the grid is down 15 percent due to co-generation. But the use of central station electricity resumes its growth in the 1990's, and on a net basis, returns to 1978 levels by the year 2000. This is because all cost-effective retrofitting of buildings has taken place by 1990, and from this time until the end of the century economic growth is reflected in increased electricity use in the building and industrial sectors. The study determined that if rational economics were closely followed, entirely new industrial facilities with different energy use characteristics would be constructed during the rest of the century.

In addition, the increased purchase of coal consumption equipment for industrial sites would become a trend in energy technology markets. These would include low Btu gasifiers, atmospheric fluidized bed boilers, and high efficiency conventional boilers. Another major trend envisioned by Mellon researchers is the installation of co-generation units at new sites of major steam-consuming industrial firms. "The most competitive co-generation system is a gas-fired turbine that generates electricity and then uses waste heat from the turbine to make steam," the report concludes.

Utility monopoly status: A myth?

Employing economic arguments in its effort to debunk accepted maxims such as "energy is scarce," "energy costs will increase," "environmentalists are causing the problem," and "conservation inhibits economic growth," the Mellon researchers finally confront the "myth" that the generation of electricity is a natural monopoly.

"As a nation, it is important to recognize that the generation of electricity is not a natural monopoly," the Mellon researchers proclaim.

Returning to the notion that centrally generated electricity at current prices is already uncompetitive in several energy service markets, the Mellon investigators contend that rising prices, implemented by electric utilities to alleviate financial distress, will simply exacerbate the problem. "To say you can solve utilities' problems by raising rates is much like saying we could solve the problems of Chrysler by raising the price of their automobiles," Bakke said.

Without institutional changes, electricity is also at a significant competitive disadvantage with co-generation and other non-centralized sources of electric generation, the study maintains. Yet, it is believed that the market for electricity production is potentially as competitive as oil and gas production. Noting that there is already competition between coal, nuclear power, and hydro power for generation, it is considered critical that unconventional renewable sources of electricity be allowed to compete with more conventional ones. Thus, serious consideration should be given to separating generation from the distribution of electricity.

Continued on page 6

Figure 1

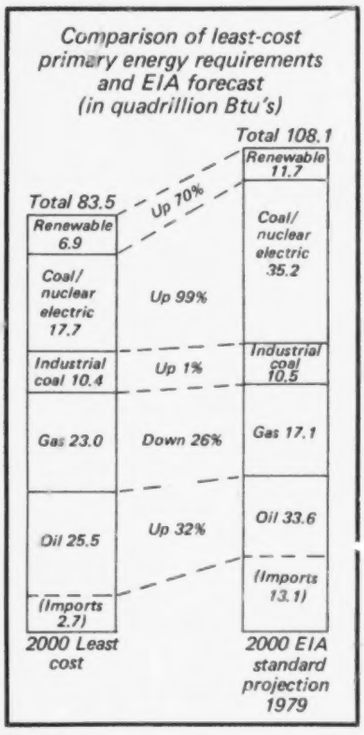


Figure 2

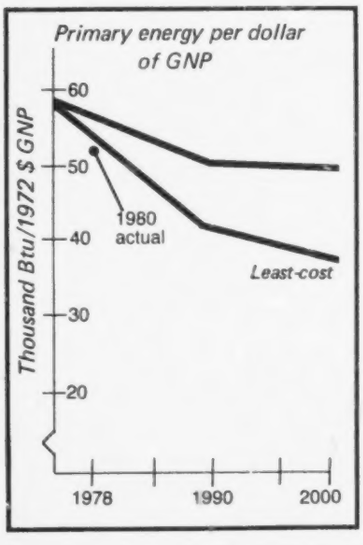
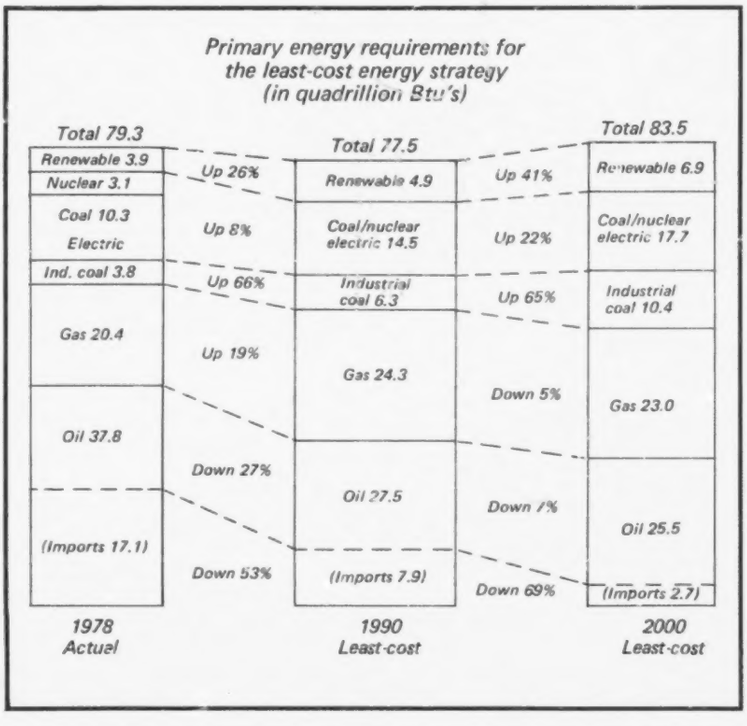


Figure 3



Advertiser and advertising agency assume liability for all contents (including text representation and illustrations) of advertisements printed, and also assume responsibility for any claims arising therefrom made against the publisher. It is the advertiser's or agency's responsibility to obtain appropriate releases on any items or individuals pictured in the advertisement.

ELECTRIC LIGHT & POWER (USPS 858-860) is published monthly. Copyright 1981, by Technical Publishing, a company of the Dun & Bradstreet Corporation—all rights reserved. James B. Tafel, Chairman; John K. Abely, President; Robert L. Dickson, Executive Vice President; John R. Emery, Senior Vice President; Robert J. (Duke) Kiesel, Publisher, Editorial and Executives offices: 1301 S. Grove Ave., Barrington, IL 60010. Phone (312) 381-1840. Distributed by controlled circulation to executives and engineers in U.S. electric utilities and consulting engineering firms. To all others there is a subscription charge of $34 per year (U.S.) $40 (Canada); and £36 foreign, £62 foreign air mail). Sole agent for all subscriptions outside the U.S.A. and Canada is J.B. Tratsart Ltd., 154a Greenford Road, Harrow, Middlesex HA 13QT. England. Single copy prices $3.00 (U.S.) $4.00 (Canada); and £4 (Foreign); Second-class postage paid at Barrington, IL 60010 and at additional mailing office. Postmaster: Send form 3579 to ELECTRIC LIGHT & POWER, 1301 S. Grove Ave., Barrington IL 60010

TMI cleanup . . .
from page 1

According to a spokesman in the Office of Management and Budget, federal funding will be from $110 to $120 million over a period of four years. This includes the approximately $37 million that has already been earmarked in FY 1982 for cleanup research and development activities in the budget of the Department of Energy.

Asked about previous declarations by Stockman that the administration would limit its role to certain R&D activities, the OMB spokesman conceded that the present announcement represented "a change in that earlier position" (see *EL&P*, July, 1981, page 2).

Asked what had prompted the change, the OMB spokesman said "the pressure was very strong from all parties concerned, including Pennsylvania Governor Thornburgh."

Governor Thornburgh had earlier outlined a proposal whereby 25 percent of the cleanup money would come from the nuclear industry, 25 percent from the federal government, and the remaining 50 percent to be shared among regional sources, including General Public Utilities, the Commonwealth of Pennsylvania, and the state of New Jersey (see *EL&P*, September, 1981, page 2).

The federal government's proposal to come up with over $100 million over four years, while substantial, falls short of the amount described in Thornburgh's shared cost approach. Said the governor, "It would be mistake at this point to assume that the full $190 million in federal funds I suggested as appropriate will be committed. It is very encouraging, however, to learn first hand that the President recognizes that this nation come to grips with the legacy of contamination of TMI if confidence in the nuclear option is to be maintained."

Final details of the arrangement were to be included in a letter to the governor from either White House counselor Ed Meese or DOE Secretary James Edwards. A spokesman for the governor's office said that the letter could be received as early as October 17.

GPU credit . . .
from page 5

receivable, the current value of its uranium supply (about $20 million), and 50 percent of Met Ed's coal supply not to exceed $5 million. The borrowing limit will decrease monthly beginning April 30, 1982 until it reaches zero on December 31, 1982. This arrangement is contingent upon the company being able to maintain adequate rates, Kuhns said.

GPU notes that if Met Ed's rates are "not adequate," the banks have said they will impose a modified paydown schedule which would require that all outstanding loans be repaid by the end of 1981. Also, the banks reportedly said they will not advance funds for the utility to make its April tax payment if rates are inadequate.

Also under the new agreement, Penelec will have a maximum borrowing limit of $75 million or $50 million plus an amount equal to its deferred energy balance (about $20 million in August), whichever is less. And Jersey Central has been given a maximum borrowing limit of $125 million, or $60 million plus an amount equal to its deferred energy balance (about $78 million in August), whichever is less.

While the sum of these sublimits is greater than the allowed borrowing maximum, it is the aggregate maximum that governs. Once the interim ceiling is reached, further borrowing is prohibited even if one or more of the operating companies has not reached its individual sublimit.

Borrowing limits

Finally, GPU—a borrowing entity in itself—is limited by its outstanding bank debt on October 1, 1981. On September 18 this was $37 million, a spokesman for the company said.

Commenting on the new borrowing maximum set for Jersey Central Power & Light, New Jersey Board of Public Utilities president George Barbour said, "With a continued weak cash position, the company has no choice but to agree to the terms set by the banks. The alternative would be to arrange a series of short-term loans at higher interest rates than they are currently being offered, if any other bank is in fact willing to loan money."

Deregulation . . .
from page 3

"Without minimizing the practical difficulties of accomplishing such a major institutional change, we conclude that the possible economic benefits of increased competition in this sector warrant widespread experimentation with—and feasibility studies of—utility deregulation," the Mellon researchers contend. In short, kilowatt hours may have to be produced and priced by competitive power generation entrepreneurs in order to find buyers in a market where least-cost principles prevail.

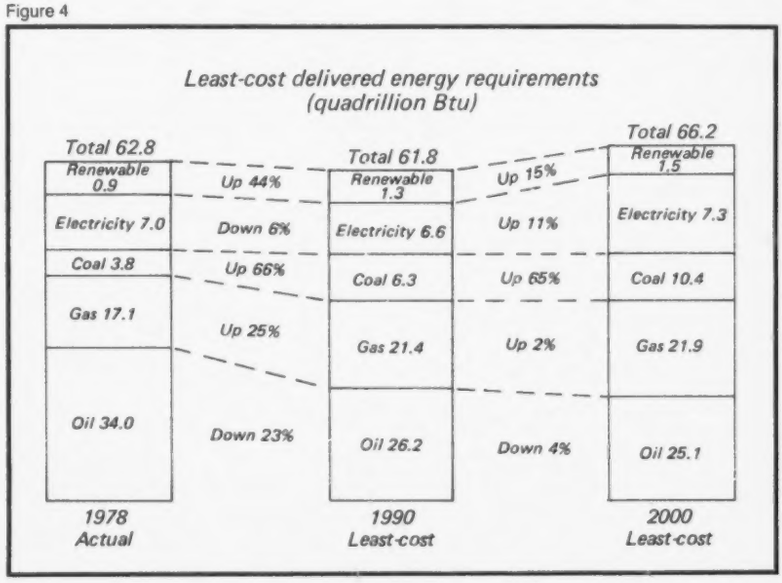
The Mellon energy study was directed by former Ford Administration conservation head Roger W. Sant who is now director of the Energy Productivity Center. He was aided by Bakke, Steven C. Carhart, and Shirish S. Mulherkar. The myths outlined in the study are said to be responsible for "our collective national ineffectiveness" in the energy area. Sant concedes that when he was with the Ford Administration he was responsible, as were others, for actually perpetuating some of these energy illusions. The present effort is an attempt to undo some of these conventions.

But while the Mellon emphasis on economics may conjure up images of budget director David Stockman at work, Institute researchers hesitate to draw an equivalence. "Our greatest disappointment will come if the Reagan Administration's "new beginning" of free market rhetoric on energy is accompanied by policies amounting merely to a scarcity-motivated government subsidization of a new set of preconceived pet solutions — which in (the Administration's) case seem to be nuclear power and accelerated fossil fuel production," Mellon researchers say.

Just how much economic factors will determine the future selection of energy supply and demand remains to be seen. Conducting an analysis and publishing results based on economic arguments alone has its risks, Mellon researcher Bakke admits. But he notes that no area of social concern has yet been identified that would invalidate the use of this economic rationale. Given current environmental constraints, for example, the least-cost strategy still works, he says.

"Markets do not work very well in a condition of scarcity," the Mellon study concludes. "In a condition of abundance, government intervention does not work at all. In the broader context of energy services, abundance appears to be our condition. Our analysis suggests that we give the economic paradigm of energy a wholehearted try. It would be the first time in a long, long time."

Figure 4

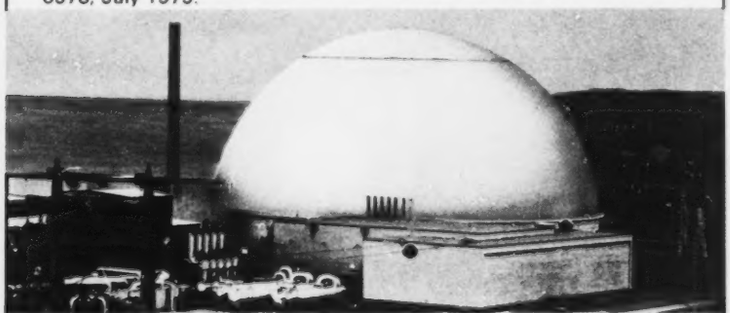


A Fast Way to Solve Condenser Air and Water In-Leakage Problems

If you have air or water in-leakage problems, call SAI for assistance. SAI will respond to your call within 24 hours with experienced personnel certified under ANSI non-destructive testing standards. SAI has provided leak detection services to over 50 utilities in this country and abroad. The SAI Gaseous Tracer Leak Detection Technique has been proven to be.....

- Fast and safe
- Performed with plant on-line
- Performed at BWR's with Radiation Exposures ALARA
- Sensitive to leaks where other methods fail:
  - Air In-Leakage - 3 x 10^{-4} CFM
  - Water In-Leakage - 2 x 10^{-5} GPM

Additional applications of the SAI Gaseous Tracer Leak Detection Technique include assisting you in meeting requirements of NUREG-0578, July 1979.



For Further Information, contact:
Science Applications, Inc. • Utility Services Division
3 Choke Cherry Road • Rockville, MD 20850 • (301) 977-4480

EL&P is looking for a new editor

Could YOU be the person we're seeking?

Electric Light & Power is looking for a strong communicator to add to its editorial staff. Successful applicant will join EL&P's aggressive editorial team in covering developments within and affecting the electric utility industry. Moderate travel required.

Applicants must possess strong writing/editing skills. Ability to understand and communicate difficult technical subjects is a must. Experience in electric utility system operations or engineering a strong plus but not imperative.

Location in EL&P's suburban-Chicago offices. Full program of company benefits.

Write: Editor, Electric Light & Power, 1301 S. Grove Ave., Barrington, IL 60010. Include resume and give salary requirements.

An equal opportunity employer

Regenerative SO_2 scrubbers look better as sulfur prices rise, market tightens

The economics of sulfur dioxide scrubbers are tipping more in favor of regenerative systems that produce by-product sulfur or sulfuric acid rather than the throwaway, sludge-type systems that most utilities have chosen so far. Sulfur prices have skyrocketed in recent years, from about $65 a ton in 1978 to about $148 a ton now.

Spokesmen for chemical and fertilizer industries are urging electric utilities that face a scrubber decision in future years to investigate the potential for the regenerative type. They've seen other U.S. sources of supply appear to peak out while foreign sources such as Poland and Iraq have proven unreliable. With prices rising and supply getting tight, and likely to remain that way for years to come, they'd love to see electric utilities become a siginifcant source of supply.

"We're certainly interested in new sources of sulfur," says Tony Longhini, director of purchasing for International Minerals and Chemicals, a major fertilizer producer (and, therefore, sulfur consumer), "and the long-term trend is for continuing tight supply unless we get some significant amounts from the utility industry." He notes one projection that sees sulfur prices climbing to $200 a ton by 1985, although he says he feels that's "on the high side." Longhini says, however, that he "certainly" sees higher sulfur prices in this decade. He says the fertilizer market consumes half the sulfur in the U.S. and can be volatile from year to year. Long-term, the purchasing official sees the demand for sulfur growing from three to five percent per year.

Another fertilizer industry spokesman, Dr. John Douglas, assistant to the manager of TVA's National Fertilizer Development Center is cautious about predicting the future, but says, "I expect the sulfur supply-demand situation in the world to remain tightly balanced for the rest of this decade." He doesn't see any significant supply from power plant scrubbers prior to 1990. Douglas notes that TVA's fertilizer development center is completely independent from the agency's power generation division. TVA has purchased scrubbers for four large power plants totaling 2500 MW, but none of the scrubbers are regenerative.

In the past couple of years, Douglas notes, there's been a change in the sulfur market situation, due to an increase in demand and a decrease in supply. He says that half a million tons of sulfur have been removed from the normal annual supply because of the Iran-Iraq war which interrupted shipments from Iraq. Poland, he reported, has also cut shipments. "We don't know why," says Douglas, but he speculates that Poland has diverted sulfur from the world market to the Soviet Union.

As a result, Douglas says that sulfur inventories in the U.S. are down from a normal level of six million tons a few years ago to three million tons of sulfur currently. With users outconsuming the supply even at today's depressed economic conditions, Douglas says, "There's no way we'll be able to keep up without pulling down inventories again."

Another sulfur market observer, John Shelton, a specialist with the U.S. Bureau of Mines, won't be pinned down to any predictions about the future for sulfur supply or prices. He notes that the market has a history of up-and-down cycles and he feels that the sulfur price may have reached a peak, for the moment at least.

Shelton agrees that events in Poland and Iraq have reduced world supply from what it could otherwise be expected to be. He adds that two major domestic sources of sulfur have either flattened or decreased in recent years. They are the "Frasch" process, which is a highly energy-intensive underground mining method, and "recovered" sulfur which comes from petroleum industry processing of "sour" natural gas and crude oil.

Demand for elemental sulfur by U.S. agriculture and industry — which is being met — is 11.6 million tons right now, says Shelton. The Bureau of Mines projection for the year 2000 shows supply, and demand, more than doubling — to 24.5 million tons of sulfur a year. Shelton sees the following sources of supply in the year 2000:

- Frasch process mining will provide 2.5 million tons a year, down from the current 6.4 million tons,
- Sulfur recovered from petroleum refining and natural gas processing is expected to rise to 14 million tons, six million from petroleum and eight from natural gas. Currently, gas processing provides 1.7 million tons and petroleum refineries produce 3.2 million tons:
- Coal gasification plants are predicted to produce two million tons per year, via recovery from the hydrogen sulfide gas that must be removed from coal gas. That source is now zero,
- Coal-burning power plants are expected to provide three million tons of sulfur a year, up from a very small amount currently,
- By-product sulfuric acid production from non-ferrous metal production is predicted to rise from one million tons of sulfur (equivalent) now to 2.5 million tons, and
- Sulfur recovery from pyrites removed in copper and molybdenum mining should reach half a million tons by the year 2000.

Shelton notes that only two electric utilities, Northern Indiana Public Service Co. and Public Service Co. of New Mexico, are reporting commercial production of sulfur to the U.S. Bureau of Mines.

For utilities evaluating future scrubber designs, Shelton notes there are three options: the throwaway type, the acid-recovery type, and the sulfur type.

The cheapest and easiest option is the throwaway sludge type, "as long as disposal continues to be environmentally acceptable," says Shelton. If a utility decides to go with a regenerative type scrubber, it must decide to recover the sulfur values in the form of elemental sulfur or sulfuric acid.

The acid option is cheaper, says the Bureau of Mines official, but presents a storage problem. There will generally be a limited amount of storage capacity for the highly corrosive, concentrated acid at a production facility — it can't just be dumped on the ground as can elemental sulfur. Therefore, if product can't be shipped, and storage is filled, the plant must be shut down.

Elemental sulfur recovery is much less market sensitive because it can be piled up, within limits, at a relatively minimal cost. However, most of the sulfur that's used in the U.S. is used in the form of sulfuric acid, says Shelton.

A recent study done by Stearns-Roger Engineering Corp. for EPRI confirms Shelton's estimate of relative costs. According to the study the capital cost of a Wellman-Lord scrubber system with an acid plant is $265 a kW; with a sulfur plant the cost is $245 per kW. The comparable capital cost of a limestone scrubber is $185 per kW. The levelized busbar cost of each option, based on by-product credits of $50 a ton for sulfur and $40 a ton for acid, in mills per kWhr, are: 15.7 for the acid option 19.0 for the sulfur option, and 12.9 for the limestone scrubber.

As shown in the table regenerative scrubbing has not been popular with utilities. Only six percent of the operating scrubbers and 10 percent of those under construction produce a sulfur or sulfuric acid by-product. Looking further into the future, none of 65 scrubbers being planned for power plants not yet under construction will produce a by-product.

Sulfur and Sulfuric Acid Recovery at Coal-Fired Power Plants

	Operating	Under Construction	Contracted or Planned	Total
Plants with sulfur, H_2SO_4 recovery	8 units, 1599 MW	5 units, 1358 MW	0	13 units, 2957 MW
Plants with SO_2 scrubbers	84 units, 28,214 MW	34 units, 14,285 MW	65 units, 35,775 MW	183 units, 78,274 MW
Percent with sulfur or acid recovery (MW basis)	6%	10%	0	4%

(Total includes three new lime scrubbers designed to produce gypsum for sale. Rest are throwaway sludge type units. Total does not include 40 planned scrubbers for which the process has not been chosen yet.)
Source: "EPA Utility FGD Survey" January, 1981. PEDCo Environmental, Inc.

As can be seen in the list of operating regenerative systems and those under construction, the leading supplier is Davy-McKee Co. of Lakeland, Florida which supplies the Wellman-Lord process. Davy-McKee had the first commercial regenerative system, which was installed at Northern Indiana Public Service Co.'s Mitchell plant in 1977. The company also had the first large installation with all four units of Public Service of New Mexico's San Juan station, totaling nearly 1800 MW.

The NIPSCO scrubber/sulfur recovery unit was retrofitted on to a 115-MW unit that burns three-percent sulfur Indiana coal. According to report at the last EPA FGD symposium, the scrubbing system was able to achieve a 90 percent sulfur removal rate at a plant output of 85 MW, but system reliability was about 75 percent due to startup and debugging problems. The paper, given by the utility's E.L. Mann and TRW's R.C. Adams, reported that during the operating period January 1, 1979 through April 30, 1980 the total FGD system operating and maintenance costs were $6.2 million and the sulfur by-product credit was $105,000. During that period the generating unit burned 349,000 tons of coal with an average sulfur content of 2.85 percent. The utility sold 2,668 tons of elemental sulfur locally.

Davy-McKee also supplied the system at Public Service of New Mexico's San Juan station. Scrubbers and a sulfur recovery system were retrofitted to three existing units — Nos. 1 and 2 are 350 MW each and No. 3 is 500 MW — about a year ago. Unit 4, a new 500 MW unit, is scheduled to start in about a year and will also be covered by the scrubber/recovery system. The units all burn a coal with a heat value of 10,000 to 11,000 Btu per lb and a sulfur content of 0.9 percent.

The scrubber/recovery system has been running at an excellent availability of 95 percent, with sulfur removal running in the 70 to 80 percent range, reports chemical plant superintendent, Jim Petrie.

He reports that the utility hired Davy-McKee to install an acid plant at the station which is slated to be in operation next year, taking care of the sulfur dioxide removed from all four units. They decided to switch from sulfur to acid because sulfur recovery required a high level of ener-

continued on page 68

Repower oil, gas-fired plants with coal-fired combined cycle

R.V. Garland
Westinghouse

Repowering modern, reheat oil- or gas-fired power plants with coal and combustion turbines is a viable alternative to adding new plants. It can add capacity while reducing, and in some cases eliminating, the use of oil or gas. A combined cycle repowered plant can improve plant heat rates as much as 12 percent, and can almost double the output for a given site depending upon the particular repowering configuration.

In the past, repowering usually involved fully depreciated non-reheat steam cycles of relatively small capacity. The existing boiler and fan systems were replaced by the combustion turbine and a supplemental boiler. These combined cycle systems included unfired and fired supplemental boilers. The steam boilers were old, and relatively small financial risks were involved. Repowered systems improved plant efficiency in the order of 10 to 20 percent and increased plant capacity as much as 100 percent, but repowering was not widely used because of the relatively small size of the total repowered system.

Much larger blocks of power are effected by repowering a modern reheat plant and the resulting gains are much more attractive. A typical reheat oil and/or natural gas fired unit with regenerative feedwater heating, less than 20 years old, will be examined. Figure 1 is a schematic representation of such a plant. There are several configurations that can be applied to repower such a plant. They convert the existing, conventional electric generating plant into a combined cycle by integrating one or more combustion turbines.

A previous analysis conducted for the Electric Power Research Institute (EPRI) has shown that the most versatile and efficient repowering configuration with the greatest potential for increased power is the supplemental boiler repowering scheme. It uses a supplementary boiler between the combustion turbine exhaust and the main boiler. (See Figure 2.) By cooling the gas to material temperature limits and producing steam in the process the existing boiler windbox can be retained. Depending upon the particular example, the supplemental boiler can help the main boiler generate and partially superheat throttle steam, or it can generate steam for the gasification system in those cases where gasification is applicable.

Exhaust gases enter the boiler windbox at about 700F so the air preheater can be eliminated. This allows the boiler exit gases to heat feedwater in a stack gas cooler.

The stack gas cooler permits splitting the feedwater stream in a strategic location, allowing a portion of the water to be heated in the stack gas cooler and the remaining portion to be heated in existing feedwater heaters. The streams then join just before they enter the main boiler economizer and the flow rate is maintained at original conditions. Since the flow through the high pressure feedwater heaters is reduced, the extraction steam quantities also diminish, thus increasing the power output of the steam turbine.

The remaining discussion of combustion turbine repowering of reheat steam power plants will cover four types of coal utilization techniques: coal derived liquids (CDL), coal derived gases (CDG), direct coal burning in an atmospheric fluid bed (AFB), and direct coal burning in a pressurized fluid bed (PFB).

To gain a meaningful impression of how repowering with coal affects plant performance, it is necessary to choose a candidate plant. Westinghouse has performed considerable study work on repowering for EPRI, applying a typical 333-MW reheat plant whose steam conditions are 2400 psig/1050F/1000F/1.5 in HgA. It is fired by oil or natural gas. The plant net heat rate is 8960 Btu/kWh (HHV) fired on a low sulfur residual oil. Item 1 of Table 1 lists its performance.

Coal derived liquids

In this analysis, it is assumed that coal derived liquids contain at least 10 weight percent hydrogen and no more than 0.2 weight percent nitrogen. State-of-the-art combustion turbines and boilers can use this fuel.

Under the above constraints, there is little difference in plant performance when comparing CDLs to petroleum fuels. Thus, it is possible to use the coal-derived fuels in a plant configuration shown schematically on Figure 3. This is essentially the same configuration used with petroleum fuel. If two Westinghouse W501 type combustion turbines are used in the repowering scheme, one could expect the repowered plant output to be about 60 percent greater and the plant thermal efficiency (heat rate) to be about 12 percent better than the conventional reheat steam plant (See Item 2 of Table 1). The use of petroleum-based fuel is eliminated.

If the gas turbines were equipped with supercharging fans, the output increases. Adding a fan and an evaporative cooler before the conventional compressor inlet is

Table 1. Performance parameters for the various repowering options.

SUMMARY OF REPOWERED PERFORMANCE USING COAL

Item	Description	CT fuel	Boiler fuel	CT MW	Main ST MW	Gasif. ST MW	Plant aux MW	Plant net MW	Plant net hr	% MW increase	% Hr improve	% red. petro fuel	Fuel to plant boundary
1	Conventional plant		Petrol	N/A	338	N/A	5	333	8960	–	–	–	Petroleum
2	Non-integrated non-supercharged CT's	Coal liq.	Coal liq.	178	360	N/A	6	533	7900	60	12	100	Coal liquid
3	Non-integrated supercharged CT's	Coal liq.	Coal liq.	226	368	N/A	15	577	7900	73	12	100	Coal liquid
4	Non-integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	172	360	N/A	4	528	7900	58	12	100	Coalgas
5	Non-integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	209	364	N/A	15	558	7900	68	12	100	Coalgas
6	Partially integrated non-supercharged CT's	Med Btu coalgas	Petrol	170	359	100	47	582	9000	75	-0.5	9	Coal & petroleum
7	Partially integrated supercharged CT's	Med Btu coalgas	Petrol	207	363	109	64	615	9070	85	-1.5	10	Coal & petroleum
8	Fully integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	170	365	144	105	577	10360	73	-15.5	100	Coal
9	Fully integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	207	371	149	121	506	10280	52	-14.5	100	Coal
10	Atmos. fluidized bed one air turbine	Coal	Petrol	55	351	N/A	6	400	5510	20	4	16	Coal & petroleum
11	Press. fluidized bed one air turbine & one expander	Coal	Petrol	63	123	N/A	3	183	8550	–	–	30	Coal & petroleum

*Heat rate based on total fuel HHV energy delivered to the plant boundary and net kW output
**Supercharging fan and evaporative cooler not shown on figure

Table 2. The options can be compared on the basis of revenue requirements.

FUEL REVENUE REQUIREMENT FOR VARIOUS REPOWERING SCHEMES

Item*	Description	CT fuel	Boiler fuel	Heat rate	Fuel revenue requirement
1	Conventional plant	–	Petrol	8960	7.66 ¢/KWH
2	Non-integrated non-supercharged CT's	Coal liq.	Coal liq.	7900	4.11 ¢/KWH
3	Non-integrated supercharged CT's	Coal liq.	Coal liq.	7900	4.11 ¢/KWH
4	Non-integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	7900	4.11 ¢/KWH
5	Non-integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	7900	4.11 ¢/KWH
6	Partially integrated non-supercharged CT's	Med Btu coalgas	Petrol	9000	3.07 ¢/KWH
7	Partially integrated supercharged CT's	Med Btu coalgas	Petrol	9070	2.98 ¢/KWH
8	Fully integrated non-supercharged CT's	Med Btu coalgas	Med Btu coalgas	10360	1.55 ¢/KWH
9	Fully integrated supercharged CT's	Med Btu coalgas	Med Btu coalgas	10280	1.54 ¢/KWH
10	Atmos. fluidized bed one air turbine	Coal	Petrol	9610	3.61 ¢/KWH
11	Press. fluidized bed one air turbine & one expander	Coal	Petrol	8550	2.72 ¢/KWH

*Items are in same sequence as those in Table 1.

Remarks
1. All figures based on fuel delivered to plant boundary.
2. Fuel costs assumed
A) Coal: $1.50/10⁶ Btu
B) Petroleum fuel, coal liquid, coalgas; all assumed $5.20/10⁶ Btu

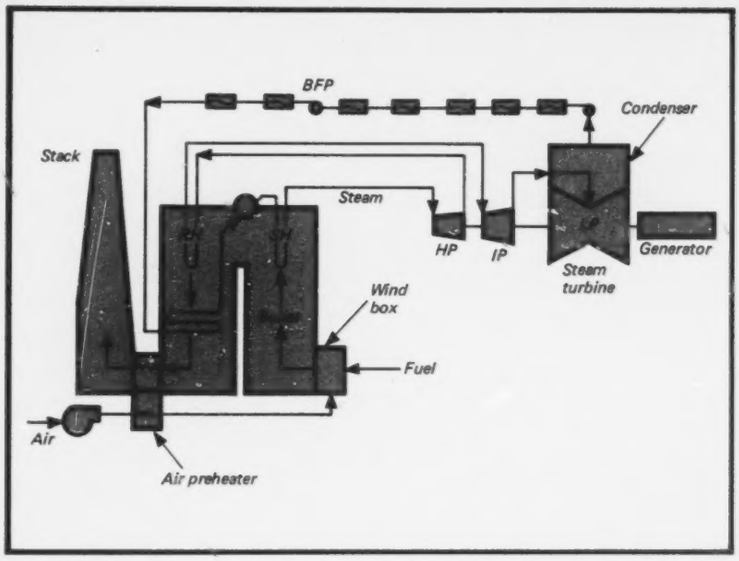


Figure 1. A good candidate for coal-fired combined cycle repowering is a typical reheat cycle with regenerative feedwater heating.

Figure 2. The reheat cycle plant can be repowered by adding a supplementary boiler and combustion turbine in front of the main boiler.

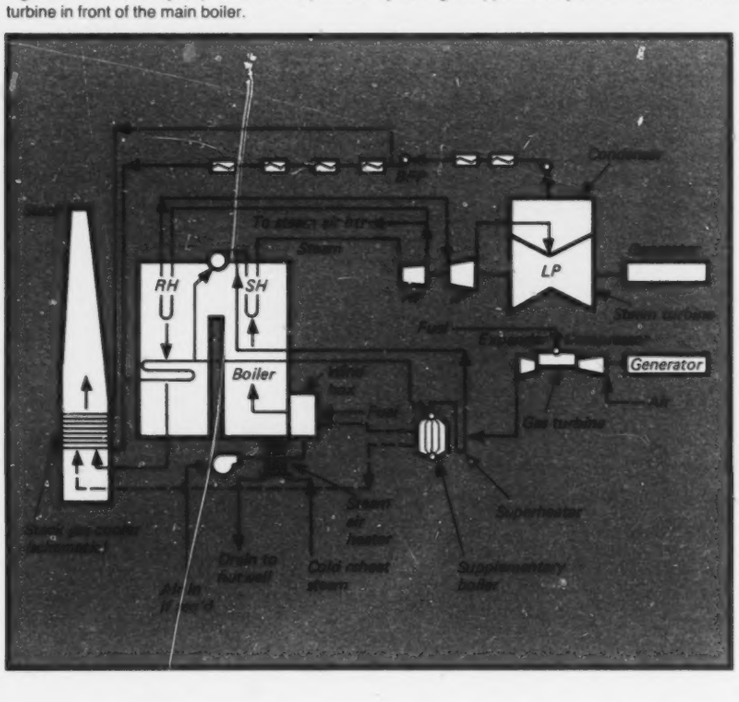
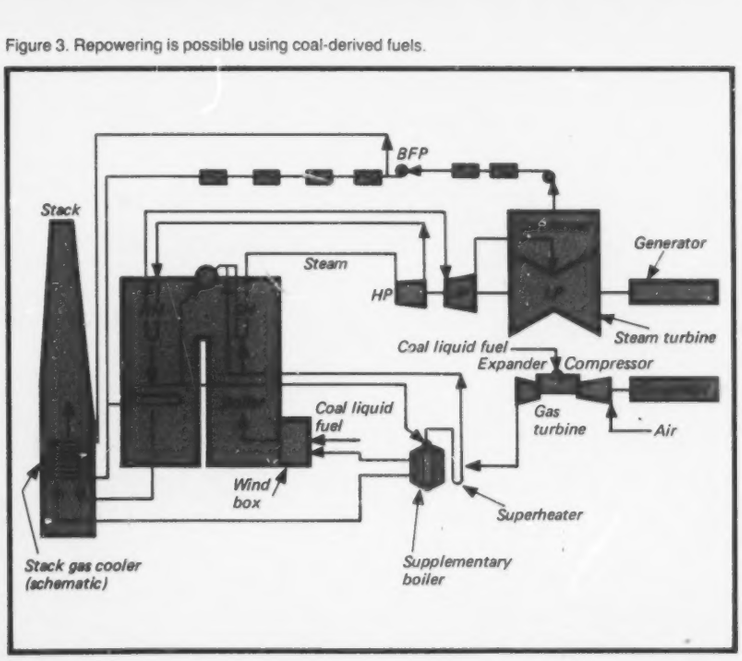


Figure 3. Repowering is possible using coal-derived fuels.



analagous to adding an additional stage with intercooling which increases the turbine mass flow and overall pressure ratio. Item 3 of Table 1 shows that repowering with two supercharged combustion turbines fired with CDL boosts the conventional plant output by 73 percent. The heat rate remains improved by 12 percent, the same as the non-supercharged case.

Plant modifications would change the existing boiler burner system; strengthen some furnace structures, alter the feed water heating system; rework the main steam turbine/generator; remove the air preheater; add a stack gas cooler for additional economizer capacity; and add hot gas ducts to the combustion turbines and the boiler. No changes require extensions beyond the state-of-the-art.

Plant emissions depend on a number of factors, including the amount of fuel-bound nitrogen and hydrogen in the fuel. The same factors must be considered for CDL fuels as is considered for the petroleum fuels. Thus, proper fuel quality will control the SOx, NOx, CO, UHC, smoke and particulate emissions. Steam or water injection to the combustion turbines is also valuable in controlling NOx.

Medium Btu coal gases, that is, coal gases manufactured from oxygen-blown gasifiers, possess gross heating values around 300 Btu/scf. These fuels contain large volume percentages of CO and H_2, typically 50 percent and 35 percent respectively. Burning these medium Btu fuels produces flame temperatures higher than normal. At normal excess air conditions, the furnace absorption tends to increase while the absorption in the convective surfaces diminishes. Medium Btu gas can be applied to repowering with combustion turbines in three ways:

1. Fuel gas supplied by pipeline from a remote source and fired in both the combustion turbines and the main boiler.

2. A partially integrated plant where the combustion turbines burn site-manufactured fuel gas while the main boiler retains oil or natural gas firing.

3. A fully integrated plant where the site-manufactured fuel gas is burned in both the turbines and the main boiler.

Schematically, there is no difference in plant configuration between the repowered plant running on a coal derived liquid and the repowered plant running on medium Btu coal gas supplied from a remote source. However, there are basic differences between the two which will be touched upon later.

When two W501 type combustion turbines, both fired on medium Btu coal gas, are applied to the repowered plant, the net plant output increases to 528 MW. The HHV heat rate, based on fuel gas supplied to the plant site at required pressure, is 7900 Btu/kWH. Thus, the power increases about 58 percent, the heat rate improves about 12 percent over the conventional plant, and no petroleum based fuel is consumed. See Item 4 of Table 1.

If the two combustion turbines are supercharged, the plant output is 558 MW; the heat rate remains about 7900/Btu/kWh. That is a 68 percent increase in output and a 12 percent improvement in heat rate. See Item 5 of Table 1.

The plant modifications required to repower on coal gas involve the same components mentioned in the coal liquid case. The boiler burner and fuel supply system require more extensive changes. Not only is the oxygen supply diminished by the vitiated air from the combustion turbines, but the fuel mass flow is about four times greater than a natural gas application.

Plant emissions do not pose serious problems regarding SOx, CO, UHC, smoke, and particulates. Increased NOx emissions are expected in the combustion turbine due to higher flame temperatures. However, steam or water injection can be used if needed. Both laboratory and field tests show that the total NOx generated by the turbine and the boiler can be reduced significantly since the turbine combustor-boiler burner repowering configuration is actually a form of staged combustion.

When the coal-derived fuel gas is manufactured on site, it is desirable to integrate the gasification system with the power generating system. Raw fuel gas is hot, as high a 2400F in some gasifiers, and it must be cooled before it can be processed to remove sulfur and particulates. Cooling the raw gas efficiently involves steam generation, feedwater heating, and clean fuel gas reheating. The additional steam generation resulting from cooling the raw gas is sent to a separate gasification system steam turbine generator.

In the partially integrated repowered system, the boiler retains oil or natural gas firing. Only the combustion turbines are coalgas fired. The main steam system is, essentially, a separate system although the combustion turbine exhaust gas is still used as a combustion air source for the main boiler. The steam generation and superheating done in the supplemental boiler is part of the gasification steam system.

The gross power output of this partially integrated scheme is 630 MW, firing two combustion turbines on coalgas and retaining low sulfur residual oil firing in the main boiler. The gasification system steam turbine, a non-reheat machine, contributes about 100 MW of the total. The auxiliary power, however, totals about 47 MW, most of which is attributable to the air separation plant compressors needed in the oxygen blown gasification system. Net output is, therefore, about 582 MW roughly 75 percent more than the conventional plant output (Item 6 of Table 1). The net heat rate is about 9000 Btu/kWH practically the same as the conventional plant heat rate, 8960 Btu/kWh.

If two supercharged combustiton turbines are applied, Item 7 of Table 1 shows the net plant output increases to 615 MW with a net heat rate of 9070 Btu/kWh. Hence, the net power increase is 85 percent and the heat rate is roughly 1.5 percent higher than the conventional plant.

A fully integrated repowered plant means that both the combustion turbines and main boiler are fired with coal gas. The plant configuration is much like the partially integrated case. The gasification system steam turbine is much larger, however, since the gasification system is larger. Gasification system steam is superheated by combustion turbine exhaust gas sensible heat in a configuration similar to the partially integrated case. Note, however, that there is no supplemental evaporator in the combustion turbine exhaust. Very great quantities of steam are generated in the gasifier gas cooler in this case. Thus, only superheating duty is required of the turbine exhaust gas energy before it is used in the main steam system.

Item 8 of Table 1 lists the performance for a non-supercharged configuration. Net output is 577 MW. The gasification system steam turbine generates 144 MW: almost 50 percent more than the similarly configured partially integrated case shown in Item 6. Note also that the plant auxiliaries in this case are more than twice as large as the Item 6 configuration. The much larger gasification system requires larger air and oxygen compressors for the air separation plant. This scheme increases the conventional output by 73 percent, but the 10,360 Btu/kWh net heat rate represents a 15.5 percent degradation in efficiency over the conventional system. The effect of the gasification plant efficiency can be quantified by comparing Items 4, 6, and 8. With coal gas supplied to the plant from a remote source, the repowered plant efficiency is 12 percent better than conventional. If the gasification plant is integrated with the powerplant, but oil firing is retained in the boiler, the repowered plant efficiency is about the same as conventional plants. With full integration, which includes coal gas firing in the main boiler, the repowered plant efficiency is about 15 percent poorer than conventional plants. However, this fully integrated example yields a net heat rate equivalent to a conventional coal fired plant with stack gas scrubbers. Of course, petroleum-based fuel use is eliminated entirely.

In the case of two supercharged turbines,

Continued on page 28

Detroit launches complex trash-to-energy system

DETROIT — City officials here announced that a huge garbage-to-energy project originally announced in 1977 is now definitely on the drawing boards. Working with Detroit Edison and Combustion Engineering, the city plans to sell $300 million worth of revenue bonds next spring to build a 3000 ton-per-day system to process and burn the city's trash. Most the the steam generated would be used in Detroit Edison's existing downtown heating system.

"The plant will be financially self supporting," said Detroit mayor Coleman Young, "with revenues generated by disposal fees paid by the city, which now go outside Detroit, and by Detroit Edison payments for the steam and electricity by-products. The substantial suburban landfill requirements of Detroit will be significantly reduced while throw-away resources within the city are recovered and constructively reused." The city generates an average of 3000 tons of trash daily. It's collected at three transfer stations and hauled to privately owned landfills outside the city.

Combustion Engineering will supply the trash processing and burning equipment, which is expected to begin operating in 1985. There will be three process streams sized so that only two are needed to yield maximum system output. The 100 ton-per-hour processing lines will be modeled after the system installed in Madison, Wisconsin, says CE manager Noel Hazzard. Each "line" will have a flail mill, a ferrous magnet system for recovering iron, a trommel screen system, and a secondary shredder for final size reduction. The system is designed to produce combustible material with a top size of six inches, with 90 percent less than four inches. The processing plant will have three of these lines.

The three processing streams will feed three CE shop-assembled spreader-stoker steam generators, that will be fueled exclusively by the refuse-derived fuel. Each boiler has a nominal capacity of 342,000 lb of steam per hour at 700F and 600 psi. The steam will be fed to an extraction turbine with a nominal capacity of 47 MW.

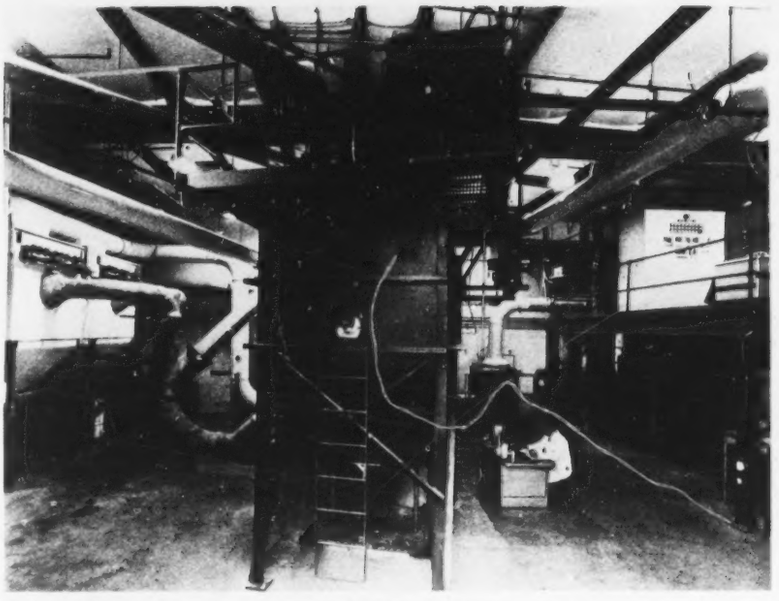
Most of the trash-energy will be used in the form of extraction steam for Detroit Edison's steam heating system. This system has 60 miles of underground main steam pipes in downtown Detroit serving about 800 customers. Originally coal-fueled, the steam generators now run largely on natural gas. The existing boilers will be replaced with the trash system.

CE's Hazzard says the system is sized so that at an average throughput rate of 3000 tons of trash a day, at average winter steam demand conditions, the system will produce 415,000 lb per hour of extraction steam at 430F and 235 psig and about four megawatts of electrical power to be sold to Detroit Edison. The steam will be produced in two boilers feeding the single turbine generator. The third processing line and boiler is redundant. The electrical output is net. At the conditions cited, the generator will produce 10.5 MW gross with 6.5 MW required for internal plant power consumption.

At the average 3000 ton-per-day throughput in periods of minimal steam demand, during spring or summer, the extraction steam will be only 200,000 lb per hour and the net electrical output will be 24 MW (30.5 MW gross.)

The turbine was sized at 47 MW, Hazzard explains, because the city and utility wanted to be able to accommodate a peak trash throughput of 4000 tons per day. They didn't want turbine-generator capacity to be a limiting factor, since there's plenty of spare capacity in the processing plant and steam generators. At that peak throughput the system could generate 557,590 lb per hour for the district heating loop, out of a total of 684,000 lb per hour from the two steam generators at turbine inlet conditions of 700F and 600 psig.

Contract negotiations among the three parties are still being finalized, Hazzard reported. He noted that CE will operate the trash processing/steam generating system, requiring a three-way deal. The city has to assure CE of a flow of trash; CE has to guarantee a supply of steam and electricity; and the utility has to agree to buy a certain amount of energy.



Radwaste facility handles 1,000 MW nuclear power plant

WINDSOR, CT — A waste incinerator designed to treat nuclear power plant liquid, slurry and dry wastes has been developed by Combustion Engineering. During prototype testing, the system handled 1,000 gallons of liquid waste, 3,200 lbs of dewatered resins and 2,200 lbs of dry combustible solids. As a result, the company feels the system is capable of handling the waste input from a 1,000 MW plant. The combustion product, ash and dry salts, can be solidified in a binding medium for final disposal. CE says the volume reduction rate varies from 50:1 to 200:1 depending on the types of combustible materials. The combustor can be seen in the center of the photo. The off-gas filtering equipment is on the left and the scrubbing hardware and control system is on the right.

Repowering . . .

from page 25

(Item 9 of Table 1), the output increases 82 percent and plant efficeincy drops 14.5 percent.

The coal fired atmospheric fluidized bed (AFB) combined cycle offers a new approach to repowering an existing plant. A coal combustor is added, replacing the conventional combustor on the combustion turbine. The AFB has both an FD and ID fan, and also uses an air preheater. The turbine receives clean air, heated in submerged tubes in the AFB, and exhausts to the main boiler at 733F. Only one non-supercharged turbine is used in this case, run on pure air at the reduced turbine inlet temperature.

No supplemental boiler is included. Instead, steam is generated in the AFB which augments production in the main boiler. All superheating is done in the main boiler superheater. Plant output increases 20 percent and the heat rate improves 4 percent over conventional operation. Most important, the use of petroleum based fuel is reduced 16 percent. See Item 10 of Table 1.

Plant emissions are environmentally acceptable. Since the AFB is maintained at 1600F, NOx is not a major problem. Limestone fed to the bed along with the coal absorbs the sulfur oxides. Particulates are controlled by a baghouse filter and cyclones.

The turbine also benefits from the low operating temperature. At 1500F, clearances and blade airfoils can be optimized for performance since cooling the various components is not as crucial as it is at conventional firing temperatures of over 2000F.

The coal fired pressurized fluidized bed (PFB) combined cycle also can be applied to repowering. This example does not utilize the 333 MW example plant; nonetheless it shows that it is possible to reduce petroleum-based fuel use up to 30 percent. (See Item 11 of Table 1.)

Table 1 shows a variety of outputs, efficiencies, and methods of repowering. To select a particular method as the best is, of course, impossible since specific economic data and the needs of individual utilities vary. However, to gain at least a measure of comparison among the various schemes, Table 2 presents the fuel revenue requirement based on some assumed fuel costs. EPRI's Technical Assessment Guide indicates that a representative cost for coal is $1.50 per million Btu; for a refined coal liquid, $5.20 per million Btu. If an acceptable petroleum-based fuel and a medium-Btu coal gas can be delivered at the same price as the coal liquid, the fuel revenue requirements for the various repowering schemes are as shown on the table.

The tabulation is not intended to reveal any clear advantage of one repowering method over another. It displays only one measure for comparison, the fuel revenue requirement. Configurations which receive coal at the plant boundary show lower fuel revenue requirements. The fully integrated examples yield the lowest figures. Even though the heat rates for Items 8 and 9 are the highest, they use 100 percent coal and manufacture the fuel gas on-site, with a revenue requirement of about 1.55 cents per kWh. However, these configurations are more complicated because the gasification system is integrated with the power plant. The table shows that, regardless of the fuel option and configuration chosen, revenue requirement is lower after repowering.

Modified scrubber . . .

continued from page 26

sumption in the system.)

As shown in Figure 2 (both figures are taken from an unpublished APS paper) sulfur removal efficiency increased to an impressively high level as pH increased, getting above 90 percent when magnesium lime was used. That could have been predicted. What was not expected, however, was that the system became subsaturated with respect to calcium sulfate at the elevated pH level, Bill Nelms explains. The signficance of that is there was no gypsum scaling. In fact, at subsaturated conditions, the system became, as he puts it, "self cleaning."

APS's Jarman explains that a key to the success of the system is the low level of oxidation in the system — that is, the relatively high level of calcium sulfite to calcium sulfate. The question became: what happened to the calcium sulfate?

Unexplained phenomenon

What was occurring, says Nelm, was the "unexplained phenomenon" of "nucleation" of the calcium sulfates and sulfites on flyash particles. Evidence of this effect could also be seen in the relative absence of sulfites and sulfates in the bleed from the thickener, says Nelms. He says that the nucleation effect can be seen in the reproduction of the electron micrograph. The large sphere in the photo (magnified 10,000 times) is a flyash particle taken from the thickener underflow. The slivers attached to the surface of the particle are calcium sulfites, says Nelms, and the plates are sulfates.

The nucleation effect explains why the test showed sulfur removal rates as 90 percent at a non-corrosive pH of 6 to 8 with no gypsum scaling, adds the engineer. The test even showed that the venturi pressure drop could be reduced from 21 in. of water down to t 6 inches with no loss of emission control. While all this was happening, Nelms points out, particulate emissions remained in compliance.

All six scrubber modules were modified, at a cost of only $15 million, says Nelms. Much of the capital expense was for a lime slaking system (described in *EL&P* December, 1980, page 46.) Since the modified scrubbers started operating in 1979, they have met the emission standards and have not been hobbled by corrosion and scaling.

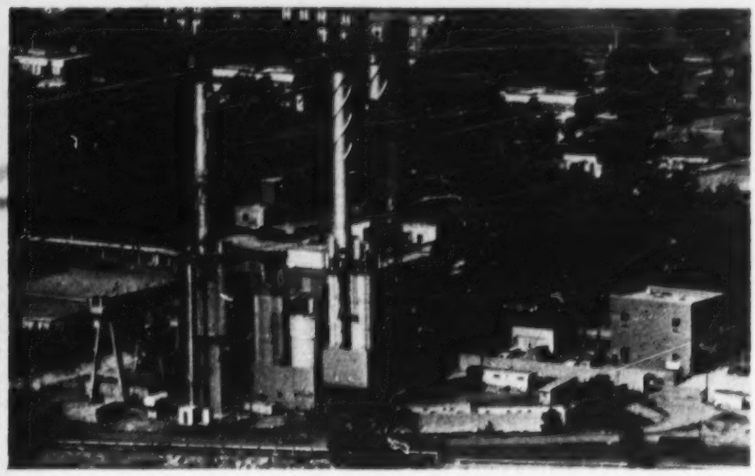
The venturi scrubber technology was not used on Four Corners units 4 and 5. These two units, 800 MW each, were built in 19?? and 1970 and were equipped with cold side electrostatic precipitators. Faced with stricter particulate and sulfur dioxide emission limits, APS decided to add wet lime spray towers for SO_2 and bag filters for the particulates. Total cost of the new system is estimated at $500 million. The spray tower will be designed to meet a 72 percent SO_2 removal rate. It will treat 80 percent of the gas flow from the two units with 20 percent used for flue gas reheat.

Why not a single-stage venturi? APS executive Jarman explains that all the results on the operations at units 1-3 were not in yet when the decisions were made for units 4 and 5. He also feels that the venturi technology is probably limited to retrofits.

Nelms, however, is looking for applications on new power plants. He hasn't interested a manufacturer in licensing his technology yet, but he's trying. He estimates that the simplified venturi for both particulate and sulfur dioxide scrubber is at least 30 percent cheaper than other wet scrubbing alternatives. Now operating a consulting business in Scottsdale, Arizona, Nelms feels it's just a matter of time before the technology catches on.

Process co-inventor Charles Turton, who still works as an engineer with Arizona Public Service says that he feels the process makes wet scrubbing "cost competitive" with dry scrubbing for low sulfur coal. However, the process is not limited to low-sulfur coal applications, in his opinion. He refers to laboratory work which shows that the coprecipitation phenomenon occurs on high sulfur coal type flue gases. Turton says that none of the existing scrubber manufacturers have shown much interest in the process yet, but some other companies have.

Fluid-bed demo starts up at Great Lakes Naval Station



A fluid bed steam generator installed at the U.S. Navy's training center on Lake Michigan consumes 27 tons of high-sulfur Illinois bituminous coal per hour.

GREAT LAKES, IL — A coal-fired fluidized bed combustion demonstration plant has started up at the U.S. Navy's Great Lakes Training Station here, announced boiler supplier, Combustion Engineering. Operation of the 50,000 lb/hr steam generator is the culmination of a $23 million program sponsored since 1976 by the U.S. Dept. of Energy.

Fueled by Illinois No. 6 coal — 3.5 percent sulfur and 10 percent ash — the fluid bed boiler is designed to provide steam at 365 psig and 560F for building heating. This is the second of the "big" fluid bed steam generation demonstrations sponsored by DOE. The first was a 100,000 lb per hour unit built by Foster Wheeler for Georgetown University's heating system in 1979.

Atmospheric pressure

The CE unit at Great Lakes is designed to operate at atmospheric pressure and a bed temperature of 1500 to 1600F, a temperature below the ash fusion point and low enough to keep nitrogen oxide emissions at an estimated level of 0.4 lb per million Btu (less than the federal standard for coal-fired power plants.) The system uses crushed limestone in the bed to capture sulfur dioxide in the flue gas right in the furnace. At a calcium-to-sulfur ratio of three to one over the operating temperature range, the system should capture 90 percent of SO_2, says CE.

Emissions

Particulate emission from the boiler is controlled in a mechanical separator and a bag filter at the back end of the process. With an inlet grain loading of 4.6 gr per scf the design outlet is 0.03 gr per scf, says CE project manager, Bill Norcross.

Norcross says that $23 million project cost covers everything spent since 1976, including a sub-scale process unit at CE's research laboratory in Connecticut. The cost of hardware at the Great Lakes facility is only $8 million, he adds, and that includes test equipment that would not be necessary in a commercial installation.

Prototype

CE says that the Great Lakes installation is the prototype for shop-assembled fluid bed systems capable of producing up to 200,000 lb per hour of steam. Norcross points out that this design is intended for industrial applications. The company is developing a design strictly for utility applications. CE says that fluid bed combustors may offer advantages over conventional coal-fired boilers because they eliminate the need for back-end sulfur scrubbers and they can accommodate a wider range of coal types.

Sulfur . . .

from page 21

gy consumption in the form of natural gas. Acid production, says Petrie, should be more cost-effective.

P.S. New Mexico wholesales its sulfur products to Phillips Petroleum Co. of Bartlesville, Oklahoma on a long-term contract basis. The arrangement is "working very well," says Petrie. He sees no problem in selling acid through Phillips. The plant's nominal capacity is 470 tons of acid per day which, according to the manager, is small as sulfuric acid plants go.

Petrie feels the long-term market outlook for by-product sale is good. "We don't look for any problems in marketing either sulfur or acid," he says.

Acid plant

The other large installation is currently under construction at Philadelphia Electric, where a regenerative acid system designed by United Engineers is being retrofitted to three generating units totaling 900 MW. The scrubbers will produce a dry sludge which will be trucked to acid plants operated by Allied Chemical Co. in Claymont, Del. and Essex Chemical Co. in Newark, N.J. The utility is putting up all the capital for the project, $312 million, and the chemical companies will operate the regeneration/acid production facilities. Operation is scheduled for 1983.

And, based on plans announced to date, that will be the last regenerative scrubber installed on a U.S. power plant, despite the improved economics.

Congratulations to Atlantic (City) Electric

Selected the Electric Utility of the Year 1981

By Electric Light & Power Magazine

No matter how the world solves its energy problems, McDermott is involved.

Bailey® Controls

©1981 Babcock & Wilcox

Babcock & Wilcox, a McDermott company

Inquire R.S. 35